Technical Support Document

for EPA's

Proposed Action on the

Louisiana Regional Haze State Implementation Plan

Prepared and Reviewed by:

Jennifer Huser
Carrie Thomas
Joe Kordzi
Erik Snyder
Michael Feldman

April 2017

Table of Contents

Tables

Figures

Louisiana Regional Haze BART Technical Support Document

1 Introduction

The purpose of this Technical Support Document (TSD) is to provide technical and supplementary information to support our proposed action on the Louisiana State Implementation Plan (SIP) revision, submitted by the Louisiana Department of Environmental Quality (LDEQ) on February 10, 2017. Consequently, this TSD is not meant to be a complete rationale for our decision. It merely provides additional information for some of the technical aspects of the basis for this action when needed. In some of the non-technical areas, our Federal Register notice provides more detail than does this TSD.

1.1 Background on Regional Haze

Regional haze is a type of visibility impairment that is produced by a multitude of sources and activities which are located across a broad geographic area and emit fine particulate matter ($PM_{2.5}$) (e.g., sulfates, nitrates, organic carbon, elemental carbon, and soil dust), and their precursors (e.g., SO_2, NO_x, and in some cases, ammonia (NH_3) and volatile organic compounds (VOCs)). Fine particle precursors react in the atmosphere to form $PM_{2.5}$, which impairs visibility by scattering and absorbing light. Visibility impairment reduces the clarity, color, and visible distance that one can see. $PM_{2.5}$ can also cause serious health effects and mortality in humans and contributes to environmental effects such as acid deposition and eutrophication.

Data from the existing visibility monitoring network, the "Interagency Monitoring of Protected Visual Environments" (IMPROVE) monitoring network, show that visibility impairment caused by air pollution occurs virtually all the time at most national parks and wilderness areas. The average visual range[1] in many Class I areas (*i.e.*, national parks and memorial parks, wilderness areas, and international parks meeting certain size criteria) in the western United States is 100-150 kilometers, or about one-half to two-thirds of the visual range that would exist without anthropogenic air pollution. In most of the eastern Class I areas of the United States, the average visual range is less than 30 kilometers, or about one-fifth of the visual range that would exist under estimated natural conditions. 64 FR 35714, 35715 (July 1, 1999).

1.2 Regional Haze Requirements

The goal of the Regional Haze Rule is to restore natural visibility conditions by 2064 at the 156 Class I areas identified in the 1977 Clean Air Act Amendments.[2] Regional haze implementation plans must contain measures that make "reasonable progress" toward this goal by reducing anthropogenic emissions that cause haze. The Regional Haze Rule sets out specific requirements for states' initial regional haze SIPs. In particular, each plan must establish a long term strategy that ensures reasonable progress toward achieving natural visibility conditions in each Class I

---

[1] Visual range is the greatest distance, in kilometers or miles, at which a dark object can be viewed against the sky.
[2] 40 CFR 51.301defines natural conditions: "Natural conditions reflect naturally occurring phenomena that reduce visibility as measured in terms of light extinction, visual range, contrast, or coloration."

area affected by the emissions from sources within the state. In addition, for each Class I area within the state's boundaries, the plan must establish a reasonable progress goal for the first planning period that ends on July 31, 2018. The long-term strategy must include enforceable emission limits and other measures as necessary to achieve the reasonable progress goal. Regional haze plans must also give specific attention to certain stationary sources that were in existence on August 7, 1977, but were not in operation before August 7, 1962. These sources, where appropriate, are required to install Best Available Retrofit Technology (BART) controls to eliminate or reduce visibility impairment. More details on regional plan requirements are summarized in the Federal Register notice for this action.

1.3 Relationship of this TSD and Our Proposed Action to Our Previous Actions on the Louisiana Regional Haze SIP

The Clean Air Act (CAA) requires each state to develop plans to meet various air quality requirements, including protection of visibility.[3] The plans developed by a state are referred to as State Implementation Plans or SIPs. A state must submit its SIPs and SIP revisions to EPA for approval. Once approved, a SIP is federally enforceable, that is enforceable by EPA and citizens under the CAA. If a state fails to make a required SIP submittal or if we find that a state's required submittal is incomplete or unapprovable in whole or in part, then we must promulgate a Federal Implementation Plan (FIP) to fill this regulatory gap within 2 years unless we approve a SIP revision correcting the deficiencies before promulgating a FIP. (CAA section 110(c)(1)).

To address the first implementation period, the State of Louisiana submitted a Regional Haze SIP on June 13, 2008 (hereafter referred to as the 2008 Louisiana Regional Haze SIP). We acted on that submittal in two separate actions: a limited disapproval (77 FR 33642; June 7, 2012) because the SIP relied on the remanded Clean Air Interstate Rule (CAIR) to address the impact of emissions from the State's Electric Generating Units (EGUs); and a partial limited approval/partial disapproval (77 FR 39425; July 3, 2012) noting deficiencies in the SIP revision that did not meet the applicable requirements of the CAA and EPA's regulations as set forth in sections 169A and 169B of the CAA and in 40 CFR 51.300-308.

In our final action on June 7, 2012, we found that the requirements of section 169A of the CAA were not met because the 2008 Louisiana Regional Haze SIP did not include fully approvable measures for meeting the requirements of 40 CFR 51.308(d)(3) and 51.308(e) with respect to emissions of NOx and SO_2 from electric generating units. We also determined that the Cross State Air Pollution Rule (CSAPR), a rule issued in 2011 to address the interstate transport of NOx and SO_2 in the eastern United States would, like CAIR, provide for greater reasonable progress towards the national goal than would BART for states in which CSAPR applies.4 We finalized that rule on May 30, 2012 (77 FR 33642). Based on this finding, we also revised the Regional Haze Rule to allow CSAPR states to substitute participation in the trading programs under CSAPR for source-specific BART. States such as Louisiana that are subject to the

[3] See CAA sections 110(a), 169A, and 169B.
[4] 76 FR 82219.

requirements of the CSAPR trading program only for ozone season nitrogen oxides (NOx) can still substitute CSAPR for BART for NOx, but must address BART for EGUs for SO_2 and other visibility impairing pollutants.[5]

On February 10, 2017, Louisiana submitted a SIP revision intended to address the deficiencies related to BART for EGU sources (2017 Louisiana Regional Haze SIP or 2017 SIP revision), which is the subject of this proposed action. This TSD provides technical and supplementary information to support our proposed action on that SIP revision.

Throughout this document, we may use language such as, "we find" or other similar phrases that on the surface would suggest a final determination has been made. However, all aspects of our TSD should be considered to be part of our proposal and are subject to change based on comments and other information we may receive during our public comment period.

2 Best Available Retrofit Technology (BART)

2.1 Identification of BART Eligible Sources and Subject to BART Sources

States are required to identify all BART-eligible sources within their boundaries by utilizing the three eligibility crieteria in the BART Guidelines (70 FR 39103, 39158, March 6, 2005) and the Regional Haze regulations (40 CFR 51.301):

1) One or more emission units at the facility fit within one of the 26 categories listed in the BART Guidelines;
2) The emission unit(s) began operation on or after August 6, 1962, and the unit was in existence on August 6, 1977; and
3) The potential emissions of any visibility-impairing pollutant from subject units are 250 tons or more per year. Sources that meet all three of these criteria are considered BART-eligible. In our proposed partial disapproval and partial limited approval (77 FR 11839) of the 2008 Louisiana Regional Haze SIP, we approved LDEQ's identification of 76 BART-eligible sources.

Once a list of BART-eligible sources within a state has been compiled, states must determine whether to make BART determinations for all the sources or to consider exempting some of them from BART because they may not reasonably be anticipated to cause or contribute to any visibility impairment in a Class I area. The BART Guidelines present several options that rely on modeling analyses and/or emissions analysis approaches to determine if a source may reasonably be anticipated to cause or contribute to visibility impairment in a Class I area. A source that may not be reasonably anticipated to cause or contribute to any visibility impairment in a Class I area is not "subject to BART," and for such sources, a state need not apply the five statutory factors to make a BART determination. In our proposed partial disapproval and partial limited approval (77 FR 11839) of the 2008 Louisiana Regional Haze SIP, we proposed to approve LDEQ's modeling that identified which sources are exempt from BART. Because LDEQ chose to meet BART requirements for EGUs for SO_2 and NOx by participation in CAIR, and because

[5] 76 FR 82224.

modeling results demonstrated that the PM emissions from EGUs did not warrant further control, they did not submit source specific BART evaluations for EGU sources identified as subject to BART. Our limited disapproval of the 2008 Louisiana Regional Haze SIP with specific regard to EGUs (77 FR 33640, 33641) was based on deficiencies in the submittal arising from the state's reliance on CAIR to meet certain regional haze requirements. States such as Louisiana that are subject to the requirements of the CSAPR trading program only for NOx must still address BART for EGUs for SO_2 and other visibility impairing pollutants.[6]

The following table lists the EGU sources that were identified in the 2008 Louisiana Regional Haze SIP submittal as BART-eligible.

Table 1: Identification of BART-Eligible EGU Sources

Facility Name	Units	Parish
Cleco Rodemacher/Brame	Nesbitt I (Unit 1) Rodemacher II (Unit 2)	Rapides
Cleco Teche	Unit 3	St. Mary
Entergy Sterlington	Unit 7	Ouachita
Entergy Michoud	Units 2 and 3	Orleans
Entergy Waterford	Units 1, 2, and auxiliary boiler	St. Charles
Entergy Willow Glen	Units 2, 3, 4, 5, auxiliary boiler	Iberville
Entergy Ninemile Point	Units 4 and 5	Jefferson
Entergy Nelson*	Units 4, 6, and auxiliary boiler	Calcasieu
Entergy Little Gypsy	Units 2, 3, and auxiliary boiler	St. Charles
Louisiana Generating (NRG) Big Cajun I	Units 1 and 2	Point Coupee
Louisiana Generating (NRG) Big Cajun II	Units 1, and 2	Point Coupee
Louisiana Energy and Power Authority Plaquemine Steam Plant	Boilers 1 and 2	Iberville
Louisiana Energy and Power Authority Morgan City Steam Plant	Units 1, 2, 3, and 4 boilers	St. Mary/St. Martin
City of Ruston – Ruston Electric Generating Plant	Boilers 1, 2, and 3	Lincoln
Lafayette Utilities System Louis "Doc" Bonin Electric Generating Station	Units 1, 2, and 3	Lafayette

[6] 76 FR 82219, 82224 (Dec. 30, 2011).

Terrebonne Parish Consolidated Government Houma Generating Station	Units 15 and 16	Terrebonne
City of Natchitoches Utility Department	3 boilers	Natchitoches

* This TSD does not evaluate the portion of the LDEQ's SIP submittal concerning the BART analysis for Entergy Nelson. We will address BART for Entergy Nelson in a future rulemaking.

3 Evaluating Which Sources Are Subject to BART

Because Louisiana's 2008 Regional Haze SIP relied on CAIR as better than BART for EGUs, the submittal did not include a determination of which BART-eligible EGUs were subject to BART. On May 19, 2015, we sent CAA Section 114 letters to several BART-eligible sources in Louisiana. In those letters, we noted our understanding that the sources were actively working with LDEQ to develop a SIP. However, in order to be in a position to develop a FIP should that be necessary, we requested information regarding the BART-eligible sources. The Section 114 letters required sources to conduct modeling to determine if the sources were subject to BART, and included a modeling protocol. The letters also requested that a BART analysis be performed in accordance with the BART Guidelines for those sources determined to be subject to BART. We worked closely with those BART-eligible facilities and with LDEQ to this end, and all the information we received from the facilities was also sent to LDEQ. As a result, the LDEQ submitted a revised SIP submittal on February 10, 2017, (2017 Louisiana Regional Haze SIP) that evaluates BART-eligible EGUs in the State and provides a BART determination for each such source for all visibility impairing pollutants except NOx. This proposal addresses the entire 2017 Louisiana Regional Haze SIP, but for the portion concerning one BART-eligible EGU facility, specifically the Entergy Nelson facility. We will propose action on the Entergy Nelson portion of the SIP at a later date. We note that Louisiana unintentionally omitted discussion of two BART-eligible facilities in its 2017 Louisiana Regional Haze SIP: Terrebonne Parish Consolidated Government Houma Generating Station and Louisiana Energy and Power Authority Plaquemine Steam Plant. We will address these two sources in the model plant analysis section below.

3.1 Sources that are No Longer in Operation

Four sources that were identified as BART-eligible have since retired from operation, rendering them no longer subject to the requirements of the Regional Haze Rule. As we discuss below, the LDEQ provided documentation supporting permit recissions to make these retirements permanent and enforceable.

The Louisiana Energy and Power Authority, Morgan City Steam Plant (Joseph J. Cefalu Sr. Municipal Steam Plant) permit recission was approved by LDEQ on July 6, 2015. By rescinding the Permit Nos. 2660-00006-V3, 2660-00006-IV2, and 2660-00006-IR0, the LDEQ made the closure of this site enforceable and permanent. Therefore, the Morgan City Steam Plant is no longer subject to BART and must obtain a new permit if it wishes to start up again.

The City of Ruston, Ruston Electrical Generating Station permit recission was approved by LDEQ on July 19, 2007. By rescinding the Permit Nos. 1720-00007-V0 and 1720-00007-IV1, the LDEQ made the closure of this site enforceable and permanent. Therefore, the Ruston Electrical Generating Station is no longer subject to BART and must obtain a new permit if it wishes to start up again.

The City of Natchitoches Utility Department, Power Plant #1 permit recission was approved by LDEQ on August 25, 2010. By rescinding the Permit No. 1980-00009-IV1, the LDEQ made the closure of this site enforceable and the permanent. Therefore, the City of Natchitoches Power Plant #1 is no longer subject to BART and must obtain a new permit it if wishes to start up again.

In addition, Entergy Michoud Units 2 and 3 were identified as BART-eligible. By letter dated August 10, 2016, Entergy System Operating Committee elected to permanently retire the Michoud generating units 2 and 3, effective June 1, 2016. This action was described in detail through a permit application to the state. As of the time of this proposal, LDEQ has not yet finalized that permit. The 2017 Louisiana Regional Haze SIP includes the Air Permit Briefing Sheet that confirms Entergy's request to remove Units 2 and 3 from the permit.[7] We propose to approve the SIP based on the draft permit, and note that we expect the proposed permit removing Units 2 and 3 to be final before we take final action to approve this portion of the 2017 Louisiana Regional Haze SIP. Alternatively, LDEQ could submit another enforceable document to ensure that Units 2 and 3 cannot restart without a BART analysis and emission limits, or demonstrate the units have been deconstructed to the point that they cannot restart without obtaining a new NSR permit, making them not operational during the timeframe for BART eligibility.

3.2 Sources that Screened Out of BART

Once a list of BART-eligible sources still in operation within a state has been compiled, the state must determine whether to make BART determinations for all of them or to consider exempting some of them from BART because they are not reasonably anticipated to cause or contribute to any visibility impairment in a Class I area. The BART Guidelines present several options that rely on modeling analyses and/or emissions analyses to determine if a source is not reasonably anticipated to cause or contribute to visibility impairment in a Class I area. A source that is not reasonably anticipated to cause or contribute to any visibility impairment in a Class I area is not "subject to BART," and for such sources, a state need not apply the five statutory factors to make a BART determination.[8] Those sources are determined to be not subject to BART. Sources that are reasonably anticipated to cause or contribute to any visibility impairment in a Class I area are subject-to-BART.[9] For each source subject to BART, 40 CFR 51.308(e)(1)(ii)(A) requires that the LDEQ identify the level of control representing BART after considering the factors set out in CAA section 169A(g)(2). To determine which sources are anticipated to contribute to visibility

---

[7] See Appendix D of the 2017 LA RH SIP submittal.
[8] See 40 C.F.R. Part 51, Appendix Y, III, How to Identify Sources "Subject to BART".
[9] *Id.*

impairment, the BART Guidelines state "you can use CALPUFF or other appropriate model to estimate the visibility impacts from a single source at a Class I area."[10]

3.2.1 Visibility Impairment Threshold

The preamble to the BART Guidelines advises that, "for purposes of determining which sources are subject to BART, states should consider a 1.0 deciview change or more from an individual source to 'cause' visibility impairment, and a change of 0.5 deciviews to 'contribute' to impairment."[11] It further advises that "states should have discretion to set an appropriate threshold depending on the facts of the situation," and describes situations in which states may wish to exercise that discretion, mainly in situations in which a number of sources in an area were all contributing fairly equally to the visibility impairment of a Class I area. In Louisiana's 2008 Regional Haze SIP submittal, the LDEQ used a contribution threshold of 0.5 dv for determining which sources are subject to BART, and we approved this threshold in our previous action.[12] The LDEQ appropriately applied this threshold for determining whether the EGUs addressed in this proposal are subject to BART.

3.2.2 Model Plant Analysis

As part of our development of the BART Guidelines, we developed analyses of model plants with representative plume and stack characteristics for both EGU and non-EGU sources using the CALPUFF model.[13] As we discuss in the BART Guidelines,[14] based on those analyses, we believe that sources that emit less than 1,000 tons per year of NO_X and SO_2 and that are located more than 100 km from any Class I area can be exempted from the BART determination. The BART Guidelines note that the model plant concept can be extended using additional modeling analyses to ratios of emission levels and distances other than 1,000 tons/100 km. The BART Guidelines explain that: "you may find based on representative plant analyses that certain types of sources are not reasonably anticipated to cause or contribute to visibility impairment. To do this, you may conduct your own modeling to establish emission levels and distances from Class I areas on which you can rely to exempt sources with those characteristics."[15] Modeling analyses of representative plants are used to reflect groupings of specific sources with important common characteristics.

As we mention above, we note that Louisiana unintentionally omitted discussion of two BART-eligible facilities in its 2017 Louisiana Regional Haze SIP: Terrebonne Parish Consolidated Government Houma Generating Station (Houma) and Louisiana Energy and Power Authority Plaquemine Steam Plant (Plaquemine). However, Louisiana's 2008 Regional Haze SIP submittal identified these two sources as BART-eligible, and we approved the inclusion of these two

---

[10] See 40 C.F.R. Part 51, Appendix Y, III, How to Identify Sources "Subject to BART".
[11] 70 FR 39104, 39120 (July 6, 2005), [40 C.F.R. Part 51, Appendix Y].
[12] See, 77 FR 11839, 11849 (February 28, 2012).
[13] CALPUFF Analysis in Support of the June 2005 Changes to the Regional Haze Rule, U.S. Environmental Protection Agency, June 15, 2005, Docket No. OAR–2002–0076.
[14] 70 FR 39119 (July 6, 2005),
[15] 70 FR 39163 (July 6, 2005).

sources on that list in 2012.[16] The LDEQ has indicated that it inadvertently failed to address whether these two sources are subject to BART in the 2017 Regional Haze SIP. These two sources were included in its 2008 Regional Haze SIP, but Louisiana relied on CAIR better than BART coverage for these sources when they adopted their 2008 SIP. Therefore, we have evaluated these two sources based on available information to determine whether they are subject to BART. We are not relying on the 1000 tpy/100 km model plant approach but are instead relying on existing modeling included in the 2008 Louisiana Regional Haze SIP as being a representative plant analysis for the purpose of establishing emission levels and distances to exempt BART-eligible sources. Specifically, the 2008 Louisiana Regional Haze SIP included review of CALPUFF modeling of a source owner, Valero, which demonstrated that Valero's BART-eligible sources do not cause or contribute to visibility impairment at the nearby Class I area, Breton National Wildlife Refuge (Breton). The Valero plant is representative (similar stack height and parameters) of the Houma and Plaquemine sources and can therefore be relied on in a model plant analysis to demonstrate that, based on baseline emissions and distance to the Class I area, the Houma and Plaquemine sources are not anticipated to cause or contribute to visibility impairment at Breton and are therefore not subject to BART.[17] We analyzed the ratio of visibility impairing pollutants, denoted as 'Q' (NOx, SO_2, and PM-10 in tons/year)[18] to the distance, denoted as 'D' (distance of source to Breton in km). For example, if two sources were similar but one has a lower Q/D value, the lower ratio value (either due to lower emissions and/or greater distance) would be expected to have smaller visibility impacts at Breton. The Q/D ratio for Houma and Plaquemine are significantly lower compared to Valero's ratio (See Table 3). The Q/D ratios of Houma are approximately 20% of Valero's, and Plaquemine's ratio is less than 10% of Valero's Q/D ratio, and modeled impacts of the Valero source were less than the 0.5 dv threshold. Therefore, the data demonstrates that visibility impacts from the BART-eligible units at Houma and Plaquemine are reasonably anticipated to be less than the modeled impacts from Valero and less than the 0.5 dv threshold to screen out. See the CALPUFF Modeling TSD for additional discussion of the model plant analysis.

We also note that on December 11, 2015, the Lafayette Utilities System Louis "Doc" Bonin Generating Station advised our Clean Air Markets Division that: Unit 1 last operated on June 22, 2011, and was put into cold storage on June 1, 2013; Unit 2 last operated on July 5, 2013, and was put into cold storage on June 29, 2014; and Unit 3 last operated on August 27, 2013, and was put into cold storage on June 24, 2014. The Midcontinent Independent System Operator (MISO) is currently conducting a study to predict the future use of these unit(s) for peaking purposes. If it is determined that these units are no longer necessary to facilitate electrical power generation, they will be retired.[19] However, at this time Lafayette Utilities System has not yet submitted a request to rescind the permit for the Louis "Doc" Bonin Electric Generating Station. Because placing the units in cold storage is not a permanent and enforceable closure under the

[16] See Appendix E of the 2008 Louisiana RH SIP contained in the docket for the rulemaking at: 77 FR 11839, 11848.

[17] See 40 CFR Part 51 Appendix Y.

[18] To calculate Q, the maximum 24-hr emissions for NOx, SO_2 and PM from the 2000-2004 baseline were identified for each BART-eligible unit at a source (See Table 9.3 of the 2008 Louisiana RH SIP). Emissions are not paired in time (i.e. max 24- hour NOx emissions value would not usually be on the same day as max 24-hour SO_2 emissions). The sum of these daily max NOx, PM and SO_2 emissions were summed and then multiplied by 365 days.

[19] See Appendix E of the 2017 Louisiana Regional Haze SIP

Regional Haze requirements, we included Louis "Doc" Bonin in our model plant analysis. The Q/D ratio for Louis "Doc" Bonin is significantly lower compared to Valero's Q/D ratio (See Table 3). The ratio is less than 40% of Valero's ratio and modeled impacts of the Valero source were less than the 0.5 dv threshold, which demonstrates that visibility impairment from the BART-eligible units at Louis "Doc" Bonin are reasonably anticipated to be less than the modeled impacts from Valero and below the 0.5 dv threshold to screen out. The model plant analysis demonstrates that, based on baseline emissions, the source is not anticipated to cause or contribute to visibility impairment of any Class I area, and is therefore not subject to BART. See the CALPUFF Modeling TSD for additional discussion of the model plant analysis. Because the modeling results demonstrate that Louis "Doc" Bonin is not subject to BART, we propose to approve this portion of the 2017 Louisiana Regional Haze SIP.

Table 2. Model Plant Q/D ratios

Facility	NOx (TPY)	SOx (TPY)	PM (TPY)	Facility Emissions (TPY)	Distance to Breton (km)	Q/D (TPY/km)	Max Percentile Delta DV
Houma	909.8	3.65	7.3	930.75	165	5.64	---
Plaquemine	492.75	0	0	492.75	227.1	2.17	---
Louis "Doc" Bonin	2993	7.3	109.5	3109.8	298.9	10.04	---
Valero	1876	1091	401.5	3368.5	139.3	24.18	0.484

Based on the results of the model plant analysis, we propose that the BART-eligible sources identified in the following table are not anticipated to cause or contribute to the visibility impairment at a Class I area and are not subject to BART. See the CALPUFF Modeling TSD for additional information on the model plant analysis.

Table 3. Sources Screened Out Using Model Plant Analysis

Facility Name	Units	Parish
Louisiana Energy and Power Authority Plaquemine Steam Plant	Boilers 1 and 2	Iberville
Lafayette Utilities System Louis "Doc" Bonin Electric Generating Station	Units 1, 2, and 3	Lafayette
Terrebonne Parish Consolidated Government Houma Generating Station	Units 15 and 16	Terrebonne

3.2.3 CALPUFF Modeling to Screen-out Sources

On May 19, 2015, we sent CAA Section 114 letters to several BART-eligible sources in Louisiana. These Section 114 letters required sources to conduct modeling to determine if the sources were subject to BART, and included a modeling protocol. The 2017 Regional Haze SIP submittal included an examination as required to determine whether a particular BART-eligible source causes or contributes to visibility impairment in nearby Class I areas.[20] For those sources that are not reasonably anticipated to cause or contribute to any visibility impairment in a Class I area, a BART determination is not required.[21] Those sources are determined to be not subject-to-BART. Sources determined to be reasonably anticipated to cause or contribute to any visibility impairment in a Class I area are determined to be subject-to-BART.[22] For each source subject to BART, 40 CFR 51.308(e)(1)(ii)(A) requires that the LDEQ identify the level of control representing BART after considering the factors set out in CAA section 169A(g). Based on the refined modeling effort, some sources were determined by LDEQ to have a visibility impact of less than 0.5 dv,[23] and therefore, are not subject to BART. See the CALPUFF Modeling TSD for additional information on modeling protocol, model inputs, and results.

Cleco Corporation (Cleco) owns and operates a 359 MW EGU boiler located at the Teche Power Station (Teche Unit 3) in Baldwin, St. Mary Parish, Louisiana. This unit burns natural gas, No. 2 fuel oil, and No. 4 fuel oil. This unit is not equipped with any air pollution control devices. Pursuant to a Section 114 CAA Information Request issued by us on May 19, 2015, Cleco conducted CALPUFF modeling to determine if the visibility impacts from Teche Unit 3 exceeded the BART threshold of 0.5 dv. This modeling is included as part of the 2017 Regional Hase SIP in Appendix B. Because the results of the modeling demonstrate that Teche Unit 3 has a visibility impact of less than 0.5 dv, LDEQ determined that the unit is not subject to BART.

Entergy Louisiana LLC (Entergy) owns and operates the Sterlington Generating Plant (Sterlington), which is a fossil fueled steam and electric generation facility in Ouachita Parish, Louisiana. Two units (7AB and 7C) were identified as BART-eligible emission units by LDEQ in their 2008 Regional Haze SIP submittal. Unit 7AB is a combined-cycle combustion turbine with a maximum heat input capacity of 923 million British thermal units/hr (MMBtu/hr) that primarily burns natural gas, and is equipped with a heat recovery steam generator (HRSG). The HRSG has a duct burner which uses natural gas as its primary fuel and has a heat input capacity of 221.6 MMBtu/hr. Unit 7C is a combined cycle combustion turbine with a maximum heat input capacity of 923 MMBtu/hr that primarily burns natural gas as its primary fuel and has a heat input capacity of 221.6 MMBtu/hr. Pursuant to a Section 114 CAA Information Request issued by EPA Region 6 on May 19, 2015, Entergy conducted CALPUFF modeling to determine if the visibility impacts from Sterlington exceeded the BART threshold of 0.5 dv. This modeling is included as part of the 2017 Regional Haze SIP in Appendix D. Because the results of the modeling demonstrate that Sterlington units 7AB and 7C have a visibility impact of less than 0.5 dv, LDEQ determined that the units are not subject to BART.

Louisiana Generating, LLC a subsidiary of NRG Energy owns and operates the Big Cajun I facility in Jarreau, Pointe Coupee Parish, Louisiana. Pursuant to a Section 114 CAA Information Request issued by EPA Region 6 on May 19, 2015, CB&I conducted CALPUFF modeling on

---

20 See 40 C.F.R. Part 51, Appendix Y, III, How to Identify Sources "Subject to BART"
21 Id.
22 Id.
23 In our previous action on Louisiana Regional Haze, we approved Louisiana's selection of 0.5dv as the threshold for screening out BART eligible sources. See 77 FR 11839, 11849 (February 28, 2012).

behalf of NRG to determine if the visibility impacts from Big Cajun I units 1 and 2 exceeded the BART threshold of 0.5 dv. This modeling is included as part of the 2017 Regional Haze SIP in Appendix C. Because the results of the modeling demonstrate that Big Cajun I units 1 and 2 have a visibility impact of less than 0.5 dv, the units are not subject to BART.

The Big Cajun II Power Plant is a coal-fired power station owned and operated by Louisiana Generating, LLC, (a subsidiary of NRG Energy). In our prior action on the 2008 Regional Haze SIP submittal, we approved Louisiana's determination that Big Cajun II has two BART-eligible units, Unit 1 and Unit 2.[24] Unit 1 is a coal-fired unit, and Unit 2 was formerly a coal-fired unit but is now a gas-fired unit. The LDEQ's screening modeling for Big Cajun II accounted for current operating conditions at the facility. The modeling analysis was conducted using the current enforceable short term emission limits from the facility that reflect controls installed after the 2008 Regional Haze SIP submittal. The following discussion explains why this departure from the use of the baseline period that states have typically relied on for BART screening is appropriate.

On March 6, 2013, Louisiana Generating entered a consent decree (CD) with EPA, the LDEQ, and others to resolve a complaint filed against Louisiana Generating for several violations of the CAA at Big Cajun II. *U.S. et al v. Louisiana Generating, LLC*, Civil Action No. 09-100-JJB-RLB (M.D. La.). Among other things, the CD requires Louisiana Generating to refuel Big Cajun II Unit 2 to natural gas, and install and continuously operate dry sorbent injection (DSI) at Big Cajun II Unit 1 while maintaining a 30-day rolling average SO_2 emission rate of no greater than 0.380 lb/MMBtu by no later than April 15, 2015.[25] Prior to the submittal of the 2017 Regional Haze SIP, the LDEQ and Louisiana Generating entered into an Agreed Order on Consent (AOC) that made these existing control requirements and maximum daily emission limits permanent and enforceable for BART. The AOC is included in Louisiana's 2017 SIP revision. Thus, if the EPA finalizes its proposed approval of this portion of the SIP submittal, the control requirements and emission limits will become permanent and federally enforceable for purposes of regional haze. As these controls were not installed to meet BART requirements, and existing enforceable emission limits for Units 1 and 2 prevent the source from emitting at levels seen during the 2000-2004 baseline, LDEQ's screening modeling in the 2017 Regional Haze SIP submittal utilizes the current daily emission limits for these units in the AOC as representative of the anticipated 24-hr maximum emissions for screening modeling purposes. LDEQ's modeling demonstrates that, based on these existing controls and enforceable emission limits, Big Cajun II contributes less than 0.5 dv at all impacted Class I areas, and therefore the facility is not subject to BART.

It should be noted that in addition to requiring DSI, the applicable enforcement CD requires Louisiana Generating to retire, refuel, repower, or retrofit Big Cajun II Unit 1 by no later than April 1, 2025. Louisiana Generating must notify us of which option it will select to comply with

---

[24] See TSD Table 6 in the Rulemaking Docket numbered EPA-R06-OAR-2008-0510.
[25] CD paragraph 62 in the docket for this rulemaking.

this condition no later than December 31, 2022, and any option taken would produce significantly fewer emissions.[26]

With the use of CALPUFF modeling results, Louisiana concluded that the facilities listed in Table 4 have visibility impacts of less than 0.5 dv,[27] and therefore, are not subject to BART. We are proposing to agree with this determnation:

Table 4. Sources with Visibility Impact of Less Than 0.5 dv

Facility Name	Units	Parish
Cleco Teche	Unit 3	St. Mary
Entergy Sterlington	Unit 7	Ouachita
Louisiana Generating (NRG) Big Cajun I	Units 1 and 2	Point Coupee
Louisiana Generating (NRG) Big Cajun II	Units 1 and 2	Pointe Coupee

3.3 Subject to BART Sources

With the use of CALPUFF modeling results as discussed above, Louisiana concluded that the facilities listed in Table 5 have visibility impacts greater than 0.5 dv. We are proposing to agree with this determination. These facilities are therefore subject to BART and must undergo a five-factor analysis. See the CALPUFF Modeling TSD for our review of CALPUFF modeling in the 2017 Louisiana Regional Haze SIP.

Table 5. Subject-to-BART Sources Addressed in this Proposal

Facility Name	Units	Parish
Cleco Rodemacher/Brame	Nesbitt I (Unit 1) Rodemacher II (Unit 2)	Rapides
Entergy Waterford	Units 1, 2, and auxiliary boiler	St. Charles
Entergy Willow Glen	Units 2, 3, 4, 5, and auxiliary boiler	Iberville
Entergy Ninemile Point	Units 4 and 5	Jefferson
Entergy Little Gypsy	Units 2 and 3 and auxiliary boiler	St. Charles

We note that in addition to the CALPUFF modeling included in the 2017 Louisiana Regional Haze SIP submittal, the results of CAMx modeling performed by Trinity consultants was

[26] CD paragraph 63 in the docket for this rulemaking.
[27] In our previous action on Louisiana Regional Haze, we approved Louisiana's selection of 0.5dv as the threshold for screening out BART-eligible sources. See 77 FR 11839, 11848.

included in the submittal as additional screening analyses[28] that purport to demonstrate that the baseline visibility impacts from Cleco Brame and a number of the Entergy sources[29] are significantly less than the 0.5 dv threshold established by Louisiana. However, this modeling was not conducted in accordance with the BART Guidelines and a previous modeling protocol developed for the use of CAMx modeling for BART screening (EPA, Texas and FLM representatives approved),[30,31] and does not properly assess the maximum baseline impacts. Therefore, we consider the submitted CAMx modeling to be invalid for supporting any determination of visibility impacts below 0.5 dv. We agree with LDEQ's decision to not rely on this CAMx modeling, but rather rely on the CALPUFF modeling for BART determinations.[32] We provide a detailed discussion of our review of this CAMx modeling in the CAMx Modeling TSD. We also note that for the largest emission sources, those with coal-fired units, we performed our own CAMx modeling following the BART Guidelines and consistent with previously agreed techniques and metrics of the Texas CAMx BART screening protocol to provide additional information on visibility impacts and impairment and address possible concerns with utilizing CALPUFF to assess visibility impacts at Class I areas located farther from the emission sources. See the CAMx Modeling TSD for additional information on EPA's CAMx modeling protocol, inputs, and model results.

3.3.1 1. Reliance on CSAPR to Satisfy NO_X BART

Louisiana's 2017 Regional Haze SIP submittal relies on CSAPR better than BART for NO_X for EGUs. We propose to find that the NO_X BART requirements for EGUs in Louisiana will be satisfied by our determination, proposed for separate finalization, that Louisiana's participation in CSAPR's ozone-season NO_X program is a permissible alternative to source-specific NO_X BART. We cannot finalize this portion of the proposed SIP approval unless and until we finalize the proposed finding that CSAPR continues to be better than BART[33] because finalization of that proposal provides the basis for Louisiana to rely on CSAPR participation as an alternative to source-specific EGU BART for NO_X.

---

[28] See October 10, 2016 Letter from Cleco Corporation to Vivian Aucoin and Vennetta Hayes, LDEQ, RE: Cleco Corporation Louisiana BART CAMx Modeling, included in Appendix B of the 2017 Louisiana Regional Haze SIP submittal; CAMx Modeling Report, prepared for Entergy Services by Trinity Consultants, Inc. and All 4 Inc, October 14, 2016, included in Appendix D of the 2017 Louisiana Regional Haze SIP submittal

[29] Entergy's CAMx modeling included model results for Michoud, Little Gypsy, R.S. Nelson, Ninemile Point, Willow Glen, and Waterford.

[30] Texas had over 120 BART-eligible facilities located at a wide range of distances to the nearest class I areas in their original Regional Haze SIP. Due to the distances between sources and Class I areas and the number of sources, Texas worked with EPA and FLM representatives to develop a modeling protocol to conduct BART screening of sources using CAMx photochemical modeling. Texas was the only state that screened sources using CAMx and had a protocol developed for how the modeling was to be performed and what metrics had to be evaluated for determining if a source screened out. See Guidance for the Application of the CAMx Hybrid Photochemical Grid Model to Assess Visibility Impacts of Texas BART Sources at Class I Areas, ENVIRON International, December 13, 2007, available in the docket for this action.

[31] EPA, the Texas Commission on Environmental Quality (TCEQ), and FLM representatives verbally approved the approach in 2006 and in email exchange with TCEQ representatives in February 2007 (see email from Erik Snyder (EPA) to Greg Nudd of TCEQ Feb. 13, 2007 and response email from Greg Nudd to Erik Snyder Feb. 15, 2007, available in the docket for this action).

[32] See Response to Comments in Appendix A of the 2017 Louisiana Regional Haze SIP submittal

[33] 81 FR 78954.

3.4 Sources that Deferred Five Factor Analysis Due to Change in Operation

Entergy operates five BART-eligible units at the Willow Glen Electric Generating Plant (Willow Glen) in Iberville Parish, Louisiana. Unit 2 is an EGU boiler with a maximum heat input capacity of 2,188 MMBtu/hr that burns natural gas. Unit 2 is permitted to burn fuel oil, but has not done so in several years, and has no current operational plans to burn oil at this unit in the future. Unit 3 is an EGU boiler with a maximum heat input capacity of 5,900 MMBtu/hr that burns natural gas. Unit 3 is permitted to burn fuel oil, but has not done so in several years and Entergy has no operational plans to burn oil at this unit in the future. Unit 4 is an EGU boiler with a maximum heat input capacity of 5,400 MMBtu/hr that burns natural gas. Unit 4 is permitted to burn fuel oil, but it has not done so in several years and Entergy has no current operational plans to burn oil at this unit in the future. Unit 5 is an EGU boiler with a maximum heat input capacity of 5,544 MMBtu/hr that burns natural gas. Unit 5 is permitted to burn fuel oil, but has not done so in several years, and Entergy has no operational plans to burn oil at this unit in the future. The auxiliary boiler (206 MMBtu/hr) for Unit 3 burns natural gas. The auxiliary boiler is permitted to burn fuel oil, but it has not done so in several years, and Entergy has no operational plans to burn oil at this unit in the future. Therefore, Entergy's analysis included in the Louisiana Regional Haze SIP as Appendix D addresses BART for the natural gas firing scenario and does not consider emissions from fuel oil firing.

Entergy's analysis states that if conditions change such that it becomes economic to burn fuel oil, the facility will submit a five-factor BART analysis for the fuel-oil firing scenario to Louisiana to be submitted to us as a SIP revision. Until such a SIP revision is approved, the 2017 Louisiana Regional Haze SIP precludes fuel-oil combustion at the Willow Glen facility. To make the prohibition on fuel-oil usage at Willow Glen enforceable, Entergy and LDEQ entered an AOC, included in the SIP that establishes the following requirement:

> Before fuel oil firing is allowed to take place at Units 2, 3, 4, 5, and the auxiliary boiler at the Facility, a revised BART determination must be promulgated for SO_2 and PM for the fuel oil firing scenario through a FIP or an action by the LDEQ as a SIP revision and approved by EPA such that the action will become federally enforceable.[34]

With our final approval of this portion of the SIP submittal, the conditions in the AOC will become federally enforceable for purposes of regional haze. We propose to find that this approach is adequate to address BART.[35]

---

[34] See AOC in Appendix D of the 2017 Louisiana Regional Haze SIP submittal.

[35] Under the AOC, if any of the five units at Willow Glen decides to burn fuel oil, Entergy will complete a BART analysis for each pollutant for the fuel oil firing scenario and submit the analysis to the State. Upon receiving Entergy's submission indicating that the units intend to switch to fuel oil, the State will submit a SIP revision with BART determinations for the fuel oil firing scenario for the units intending to switch to fuel oil. The sources will not begin to burn fuel oil until we have approved the submitted SIP revision containing the BART determinations.

With regard to BART requirements for the gas-firing scenario, SO_2 and PM emissions for the gas-only fired units that are subject to BART are inherently low,[36] and are so minimal that the installation of any additional PM or SO_2 controls on these units would likely achieve very small emissions reductions and have minimal visibility benefits. As there are no appropriate add-on controls and the status quo reflects the most stringent controls, we propose to agree with Louisiana that SO_2 and PM BART is no additional controls for the Willow Glen units when burning natural gas.

3.5 Louisiana's Five-Factor Analyses for SO_2 and PM BART

In determining BART, the state, or EPA if implementing a FIP, must consider the five statutory factors in section 169A of the CAA: (1) the costs of compliance; (2) the energy and non-air quality environmental impacts of compliance; (3) any existing pollution control technology in use at the source; (4) the remaining useful life of the source; and (5) the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology. *See also* 40 CFR 51.308(e)(1)(ii)(A).

All units that are subject to BART must undergo a BART analysis. Regarding this, Section 51.308(e) states:

> The determination of BART must be based on an analysis of the best system of continuous emission control technology available and associated emission reductions achievable for each BART-eligible source that is subject to BART within the State. In this analysis, the State must take into consideration the technology available, the costs of compliance, the energy and nonair quality environmental impacts of compliance, any pollution control equipment in use at the source, the remaining useful life of the source, and the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology.

This is commonly referred to as the "BART five factor analysis." The BART Guidelines break the analyses of these requirements down into five steps:[37]

STEP 1—Identify All Available Retrofit Control Technologies,
STEP 2—Eliminate Technically Infeasible Options,
STEP 3—Evaluate Control Effectiveness of Remaining Control Technologies,
STEP 4—Evaluate Impacts and Document the Results, and
STEP 5—Evaluate Visibility Impacts.

In addition, Step 4 is further broken down into 4 steps:

[36] AP 42, Fifth Edition, Volume 1, Chapter 1: External Sources, Section 1.4, Natural Gas Combustion, available here: *https://www3.epa.gov/ttn/chief/ap42/ch01/final/c01s04.pdf.*
[37] 70 FR 39103, 39164 (July 6, 2005) [40 CFR 51, App. Y].

Impact analysis part 1: Costs of compliance,
Impact analysis part 2: Energy impacts, and
Impact analysis part 3: Non-air quality environmental impacts.
Impact analysis part 4: Remaining useful life.

As mentioned previously, we disapproved portions of Louisiana's 2008 Regional Haze SIP due to the state's reliance on CAIR as an alternative to source-by-source BART for EGUs.[38] Following our limited disapproval, LDEQ worked closely with the BART-eligible facilities and with us to revise its Regional Haze SIP, which resulted in the submittal of its 2017 Regional Haze SIP. The 2017 SIP submittal includes, among other things, a five-factor BART analysis for each subject-to-BART source for PM and SO_2. Louisiana's 2017 Regional Haze SIP relies on CSAPR participation as an alternative to source-specific EGU BART for NO_X. In evaluating the State's 2017 SIP revision, we reviewed each BART analysis for SO_2 and PM for each subject-to-BART facility and other relevant information provided in the 2017 Regional Haze SIP submittal.

3.5.1 Cleco Brame Energy Center

The Cleco Brame Energy Center includes two units that are subject to BART. The Nesbitt I (Brame Unit 1) is a 440-megawatt (MW) EGU boiler that burns natural gas and is not equipped with any air pollution controls. The Rodemacher II (Brame Unit 2) is a 523-MW wall-fired EGU boiler that burns Powder River Basin (PRB) coal. In response to our Section 114 request,[39] Cleco submitted a BART applicability screening analysis to us and LDEQ on August 31, 2015. Cleco also submitted a BART five factor analysis on October 31, 2015, revised on April 14, 2016 and April 18, 2016. These analyses were adopted and incorporated into the 2017 Louisiana Regional Haze SIP.

Nesbitt 1

The Nesbitt 1 is currently permitted to burn natural gas and oil. However, this unit has not burned oil in the recent past and has recently entered into an AOC that limits the unit to burning only natural gas unless this unit undergoes an additional BART analysis for fuel oil burning.[40] We concur with this commitment. Before fuel oil firing is allowed to take place at the Nesbitt 1, a revised BART determination must be promulgated for all pollutants for the fuel oil firing scenario through our action upon and with the approval of a revised BART determination submitted by the State as a SIP revision. LDEQ did not conduct a BART five factor analysis for the Nesbitt 1, concluding that "SO_2 BART controls are satisfied through the conversion to natural gas."[41] However, we note that the BART Rule states:[42]

> Consistent with the CAA and the implementing regulations, States can adopt a more streamlined approach to making BART determinations where appropriate. Although BART determinations are based on the totality of circumstances in a given situation, such as the distance of the source from a Class I area, the type and

---

[38] 77 FR 33642.
[39] Wren Stenger, Section 114(a) Information Request letter to Darren Olagues (Cleco), May 19, 2015.
[40] See CLECO AOC in Appendix B of the 2017 Louisiana Regional Haze SIP.
[41] See pdf page 10 of the 2017 Louisiana Regional Haze SIP submittal.
[42] 70 FR 39103, 39116.

> amount of pollutant at issue, and the availability and cost of controls, it is clear that in some situations, one or more factors will clearly suggest an outcome. Thus, for example, a State need not undertake an exhaustive analysis of a source's impact on visibility resulting from relatively minor emissions of a pollutant where it is clear that controls would be costly and any improvements in visibility resulting from reductions in emissions of that pollutant would be negligible. In a scenario, for example, where a source emits thousands of tons of SO_2 but less than one hundred tons of NOx, the State could easily conclude that requiring expensive controls to reduce NOx would not be appropriate.

SO_2 and PM emissions from gas-fired units are inherently low,[43] so the installation of any additional PM or SO_2 controls on this unit would likely achieve very small emissions reductions and have minimal visibility benefits.

Before burning fuel oil at this unit, Cleco has committed to submit a five-factor BART analysis for the fuel-oil-firing scenario to Louisiana to be submitted to us as a SIP revision, and fuel oil combustion will not take place until our final approval of that SIP revision. To make the prohibition on fuel-oil usage at this unit enforceable, Cleco and LDEQ entered an AOC that establishes enforceable limits, consistent with the exclusive use of natural gas, of 3.0 lb/hr SO_2 and 37.3 lb/hr PM_{10} on 30-day rolling averages and a limitation on Nesbitt 1 analogous to the limitation for Willow Glen discussed previously.[44] This AOC is included in Louisiana's 2017 SIP revision. With our final approval of this portion of the 2017 SIP submittal and the AOC, that limitation will become federally enforceable for purposes of regional haze. We propose to find this approach adequate to meet BART.

Rodemacher 2
As the 2017 Louisiana SIP indicates,[45] recent pollution control upgrades at the Rodemacher 2 include:

- Low-NOx Burners (LNB) that were installed in 2008;
- Low-sulfur fuel began to be burned in 2009;
- Selective non-catalytic reduction (SNCR) was installed in 2014; and
- Dry sorbent injection (DSI), activated carbon injection (ACI) and fabric filter (FF) that were installed in 2015.

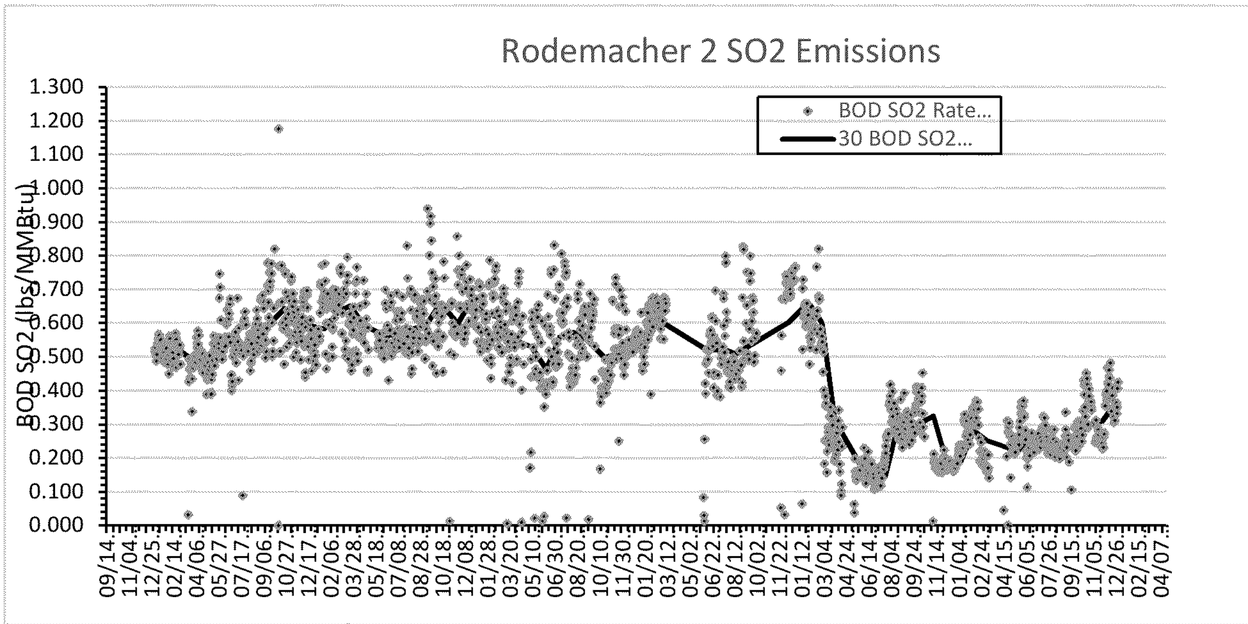
In assessing SO_2 BART, Cleco considered the five BART factors we discuss above. In Steps 1, 2, and 3, feasible control technologies and their effectiveness, Cleco considered an enhancement to the existing DSI system, dry scrubbing (Spray Dry Absorption, or SDA), and wet scrubbing (wet Flue Gas Desulfurization, or wet FGD). In considering enhanced DSI, Cleco relied upon

---

[43] AP 42, Fifth Edition, Volume 1, Chapter 1: External Sources, Section 1.4, Natural Gas Combustion, available here: *https://www3.epa.gov/ttn/chief/ap42/ch01/final/c01s04.pdf.*
[44] See AOC in Appendix B of the 2017 Louisiana Regional Haze SIP
[45] See APPENDIX B of the 2017 Louisiana Regional Haze SIP

on-site testing it had conducted to determine the performance potential of an enhanced DSI system. In response to our request for details concerning this testing,[46] Cleco did not supply the testing and replied that the testing was conducted to evaluate the effectiveness of the DSI system to control HCL for compliance with the Mercury and Air Toxics Standards (MATS), but that the CEMS monitor was operating and capturing SO_2. Below we present the Rodemacher 2 Boiler Operating Day (BOD)[47] SO_2 emissions and the 30 BOD SO_2 average:[48]

Figure 1. Rodemacher BOD SO_2 Emissions



As the above figure indicates, the Rodemacher 2 DSI system became operational on approximately 3/1/15, and that the current system is capable of achieving SO_2 emissions of approximately 0.4 lbs/MMBtu or less for sustained periods of time. Cleco determined that the current and enhanced DSI systems have SO_2 removal efficiencies of approximately 39% and 63%, respectively, with the enhanced DSI system being capable of a monthly SO_2 emission limit of 0.30 lbs/MMBtu. Cleco secured this limit as part of the same AOC referenced above for the Nesbit 1. We believe that based on the information we have presented in Figure 1, Louisiana's selection of 0.30 lbs/MMBtu on a rolling 30 day basis for SO_2 is reasonable for an enhanced DSI system on the Rodemacher 2.

In step 4, impacts, Cleco considered the cost of compliance. We have identified a number of problems with Cleco's BART analysis for Rodemacher 2 in our comments to LDEQ. Some of

---

[46] See the April 5, 2016 letter to Guy Donaldson from Bill Matthews in our docket.

[47] As in 70 FR 39103 39172 (July 6, 2005), a boiler operating day is "any 24-hour period between 12:00 midnight and the following midnight during which any fuel is combusted at any time at the steam generating unit." A 30 BOD average does not over-weigh emission spikes caused by start-up or shutdown events, as a straight 30 calendar day average has the potential to do. Thus, it better reflects the ability of the source to meet a particular emission limit.

[48] See the file, "Rodemacher 2 SO_2 emissions.xlsx" in our docket.

these issues have been adequately addressed (e.g., removal of AFUDC and escalation, 30 year life), however significant problems remain. These problems include a general lack of documentation for cost figures.

Cleco concluded that the enhanced DSI system would not require an additional capital expenses, with the increase in annual cost being due to the additional operating costs of the additional sorbent (trona). Cleco also did not provide the DSI testing information, which creates a degree of uncertainty concerning the potential control level of its current DSI system and the enhanced DSI system it reviews. Another concern was that the DSI testing that Cleco relied on was not intended to evaluate DSI for SO_2 control efficiency, which caused some uncertainty concerning the potential control level of DSI and enhanced DSI. However, because DSI and a fabric filter baghouse are already installed and operational, the cost-effectiveness of Cleco's enhanced DSI is based only on the cost of the additional reagent and no additional capital costs are involved. Consequently, we believe that the uncertainty of Cleco's enhanced DSI cost-effectiveness figures is low and that Cleco's estimated cost-effectiveness of $967/ton[49] is reasonable. However, because the cost-effectiveness of Cleco's enhanced DSI is reflected only in the cost of the additional reagent and no additional capital costs are involved, we believe that uncertainty of Cleco's enhanced DSI cost-effectiveness is low, and that Cleco's figure of $967/ton[50] is reasonable. Cleco didn't specifically address the energy impacts and non-air quality impacts of enhanced DSI, but we conclude that any considerations regarding these factors would be very minimal over the already installed DSI system.. Cleco also assessed the costs associated with installing and operating SDA and wet FGD, as discussed below.

Cleco assessed SDA and wet FGD as being capable of 0.06 and 0.04 lbs/MMBtu, respectively. We believe these efficiencies are reasonable on a 30 day BOD basis and have used them in our own analyses in past actions. However, we also believe that significant uncertainty exists with respect to Cleco's cost-effectiveness estimates for SDA and wet FGD—$8,589/ton and $5,580/ton, respectively. Based on our experience reviewing and conducting control cost analyses for many other facilities, we believe that Cleco's estimates are too high. Cleco did not supply documentation for its cost calculations, including capital cost figures. In the case of its SDA cost analysis, Cleco's Total Capital Cost figure of $492,551,139 differs from the sum of its direct costs, indirect costs, and contingency. Absent unlisted costs, we calculate that this figure should be $378,318,000.

---

49 Cleco lists this as an incremental cost-effectiveness figure for enhanced DSI over the existing DSI system. However, the enhanced DSI system has no additional capital costs, and when the already sunk capital costs of the existing DSI system are removed (which have been carried forward), the $967/ton figure becomes the average cost-effectiveness value for enhanced DSI.

50 Note that Cleco lists this as an incremental cost-effectiveness figure for enhanced DSI over the existing DSI system. However, the enhanced DSI system has no additional capital costs, and when the already sunk capital costs of the existing DSI system are removed (which have been carried forward) , the $967/ton figure becomes the cost-effectiveness value for enhanced DSI.

Under energy impacts and non-air quality impacts, Cleco concluded that wet FGD poses certain water and waste disposal problems over SDA. Cleco concluded that remaining useful life was not a factor in its cost analyses.

In assessing Step 5, visibility impacts, the state's submittal included CALPUFF modeling[51] evaluating the visibility benefits of DSI, enhanced DSI, SDA, and wet FGD. We summarize the results of that modeling in Table 6.[52]

Table 6. Anticipated visibility benefit due to controls on Cleco Rodemacher Unit 2 (CALPUFF, 98th percentile)

Class I area	Baseline Impact (dv)	Visibility benefit of controls over baseline (dv)			
		DSI[53]	Enhanced DSI	SDA	WFGD
Breton	0.724	0.134	0.226	0.436	0.445
Caney Creek	0.734	0.085	0.122	0.311	0.322

Enhanced DSI achieves benefits of approximately 0.092 dv at Breton and 0.037 dv at Caney Creek Wilderness (Caney Creek) over DSI and benefits of 0.226 dv at Breton and 0.122 dv at Caney Creek over the baseline impairment. The visibility benefits of SDA and wet FGD exceed the benefits from enhanced DSI by approximately 0.2 dv at Caney Creek and Breton. See the CALPUFF Modeling TSD for additional information.

We also performed our own CAMx modeling analysis for Cleco Rodemacher Unit 2 following the BART Guidelines to evaluate the maximum baseline visibility impacts and potential benefits from two levels of controls, DSI at 0.41 lb/MMBtu and wet FGD at 0.04 lb/MMBtu, to supplement the CALPUFF modeling. As discussed above, Louisiana relied on CALPUFF modeling to inform BART determinations consistent with the BART Guidelines. However, the use of CALPUFF is typically used for distances less than 300-400 km. The Cleco Brame source is located 352 km from Caney Creek and 422 km from Breton. CAMx provides a scientifically validated platform for assessment of visibility impacts over a wide range of source-to-receptor distances. CAMx is also more suited than some other modeling approaches for evaluating the impacts of SO_2, NO_X, VOC, and PM emissions as it has a more robust chemistry mechanism than CALPUFF. Our CAMx Modeling TSD provides a detailed description of the modeling protocol, model inputs, and model results, the latter of which is summarized in Table 7.

---

[51] CLECO Brame Energy Center BART Five-Factor Analysis, prepared by Trinity Consultants, October 31, 2015 revised on April 14, 2016 and April 18, 2016. Available in Appendix B of the 2017 Louisiana Regional Haze SIP.

[52] We note that the State's submittal also included additional screening modeling results using CAMx. As discussed above and in the CAMx Modeling TSD, this modeling was not conducted in accordance with the BART Guidelines and does not properly assess the maximum baseline impacts. Therefore, we consider this CAMx modeling to be invalid for supporting a determination of minimal impacts.

[53] DSI modeled at 0.41 lb/MMBtu, DSI and fabric filter are already installed and operational.

Table 7. Anticipated visibility benefit due to controls on Cleco Rodemacher Unit 2 (CAMx)

Class I area	Baseline Impact (dv) (maximum)	Baseline Impact (dv) (average top ten impacted days)	Visibility benefit of controls over baseline (dv) maximum impact		Visibility benefit of controls over baseline (dv) average top ten impacted days	
			DSI[54]	WFGD	DSI[55]	WFGD
Breton	0.713	0.315	0.187	0.399	0.117	0.271
Caney Creek	2.051	1.005	0.119	0.238	0.271	0.459

The CAMx-modeled visibility benefits of WFGD are 0.212 dv at Breton and 0.119 dv at Caney Creek over those from DSI for the most impacted day. Examining the top ten impacted days during the baseline period, the average benefit on this set of days of WFGD over DSI is 0.154 dv at Breton and 0.188 dv at Caney Creek. As enhanced DSI would reduce SO_2 emissions from an emission rate of 0.41 lb/MMBtu to 0.3 lb/MMBtu, enhanced DSI would lead to greater visibility benefits than DSI. Thus, the visibility benefits of WFGD compared to enhanced DSI would be smaller than those discussed above.

Nevertheless, even accounting for the problems inherent in Cleco's SDA and wet FGD cost analyses, we are cognizant of the enhanced DSI's low cost-effectiveness, and the incremental costs of obtaining the additional 0.1-0.2 dv of visibility improvement that can be achieved by SDA or wet FGD over enhanced DSI are likely high. Therefore, despite the uncertainties in the SDA and wet FGD cost-effectiveness figures, we propose to approve LDEQ's conclusion that enhanced DSI is SO_2 BART for the Rodemacher 2, with a SO_2 emission limit of 0.30 lbs/MMBtu on a 30 day rolling basis.

In assessing PM BART, Cleco notes that Rodemacher 2 is equipped with an ESP and a baghouse, which offers excellent PM control and concludes that PM BART is no further control. The AOC referenced above sets a PM emisisons limit for Rodemacher 2 of 545 lb/hr PM_{10} on a 30-day rolling basis. As discussed earlier, the BART rules allow for a more streamlined approach to making BART determinations when appropriate.[56] The BART Guidelines further state that if a BART source already has controls that are among the most stringent available and the controls are made federally enforceable for BART, the remainder of the BART analysis is unnecessary.[57] The existing ESP combined with the baghouse meets the definition of "among the most stringent controls" for PM at this unit and are made federally enforceable for BART through the AOC. The AOC allows the unit to meet the emissions limits by use of the ESP and th baghouse, conversion to natural gas only, unit retirement, or another means of achieving compliance.

[54] DSI modeled at 0.41 lb/MMBtu, DSI and fabric filter are already installed and operational.
[55] DSI modeled at 0.41 lb/MMBtu, DSI and fabric filter are already installed and operational.
[56] 70 FR 39116.
[57] 40 CFR 51 Appendix Y.IV.D.1.9.

In addition, CALPUFF visibility modeling shows that baseline impairment due to PM is very small, at 0.01 dv or less at both Breton and Caney Creek compared to the overall visibility impairment from all pollutants of approximately 0.6 dv.[58] Our CAMx modeling estimates that baseline visibility impairment due to PM emissions from the unit is less than 1% of the total visibility impairment due to the unit, at both Caney Creek and Breton.[59] We find that the visibility impacts due to PM emissions are so minimal that any additional PM controls would only result in very minimal visibility benefit that could not justify the cost of any upgrades and/or operational changes needed to achieve a more stringent emission limit. We therefore propose to agree with Louisiana that no additional controls are required to satisfy PM BART. LDEQ and Cleco entered into an AOC establishing an enforceable limit on PM_{10} consistent with current controls at 545 lb/hr on a 30-day rolling basis. As such, we agree with LDEQ's conclusion that no additional controls is acceptable for PM.

Entergy Little Gypsy

Entergy operates three BART-eligible units at Little Gypsy Generating Plant (Little Gypsy). Unit 2 is an EGU boiler with a maximum heat input capacity of 4,550 MMBtu/hr that is permitted to burn natural gas as its primary fuel, and No. 2 and No. 4 fuel oil as secondary fuels. Unit 3 is an EGU boiler with a maximum heat input capacity of 5,578 MMBtu/hr that burns natural gas, but is also permitted to burn fuel oil. The auxiliary boiler for Unit 3 has a maximum heat input capacity of 252 MMBtu/hr and is permitted to burn only natural gas. According to November 9, 2015 updated CALPUFF screening modeling conducted by Trinity Consultants on behalf of Entergy,[60] the baseline visibility impacts of Little Gypsy are greater than 0.5 dv, so the 2017 SIP revision demonstrates that the three units at Little Gypsy are subject to BART.[61]

LDEQ and Entergy entered into an AOC limiting fuel oil to ultra-low sulfur diesel (ULSD) with a sulfur content of 0.0015% for both Units 2 and 3. As the BART Guidelines state, "if a source commits to a BART determination that consists of the most stringent controls available, then there is no need to complete the remaining analyses."[62] Entergy states that during the baseline period, Units 2 and 3 burned fuel oil[63] with an average sulfur content of 0.5%. Switching to ULSD will result in a reduction of SO_2 emissions of over 99%. We find that ULSD is the most stringent control available for addressing SO_2 emissions from fuel oil burning, and we agree with LDEQ that this satisfies BART for SO_2 for Little Gypsy Unit 2.

The 2017 Louisiana Regional Haze SIP narrative does not include a BART determination for the auxiliary boiler, but the BART analysis in Appendix D of the SIP submittal does address the

---

[58] See Table 4-3 CLECO Brame Energy Center BART Five-Factor Analysis, prepared by Trinity Consultants, October 31, 2015 revised on April 14, 2016 and April 18, 2016. Available in Appendix B of the 2017 Regional Haze SIP submittal.
[59] Calculated as percent of total extinction due to the unit. See CAMx Modeling TSD for additional information.
[60] See Appendix D of the 2017 SIP submittal.
[61] See CALPUFF Modeling TSD for a summary of model results
[62] See 40 C.F.R. Part 51, Appendix Y, IV, D
[63] For this and all units herein assessed for BART, the primary fuel burned has historically been pipeline quality natural gas. Please see the TSD for more details.

auxiliary boiler and concludes that no additional controls are necessary for BART. The auxiliary boiler is permitted to only burn natural gas. We note that SO_2 and PM emissions for gas-fired units are inherently low[64] and so minimal that the installation of any additional PM or SO_2 controls on such units would likely achieve very low emissions reductions and minimal visibility benefits. As there are no appropriate add-on controls and the status quo reflects the most stringent controls, we propose to agree with LDEQ that SO_2 and PM BART is no additional controls for the Little Gypsy auxiliary boiler. For the same reason, we propose to approve LDEQ's conclusion that PM BART for Little Gypsy Units 2 and 3 during gas-firing operation is no additional controls.

With regards to PM BART for the fuel-oil-firing scenarios at Units 2 and 3, Louisiana evaluated wet ESP, wet scrubber, cyclone, and switching fuels to 0.0015% S fuel oil (ULSD). In evaluating energy and non-air quality impacts, the BART analysis identifies energy impacts associated with energy usage for ESPs and scrubbers. In addition, ESPs and scrubbers generate wastewater streams and the resulting wastewater treatment will generate filter cake, requiring land-filling. LDEQ did not identify any impacts regarding remaining useful life. The costs of compliance for these add-on control options are very high compared to their anticipated visibility benefits.[65] The modeled visibility benefits of add-on controls are very small and range from 0.0 dv to 0.037 dv for cyclone, wet scrubber, and wet ESP. Therefore, we propose that the costs of add-on PM controls do not justify the expected improvement in visibility. Accordingly, we are proposing to agree with Louisiana that the fuel sulfur content limits contained in the AOC that were determined to meet SO_2 BART also satisfy PM BART.

Entergy Ninemile Point

Entergy operates two BART-eligible units at Ninemile Point Electric Generating Plant (Ninemile Point). Unit 4 is an EGU boiler with a maximum heat input capacity of 7,146 MMBtu/hr that burns primarily natural gas and No. 2 and No. 4 fuel oil. Unit 5 is an EGU boiler with a maximum heat input capacity of 7,152 MMBtu/hr that burns primarily natural gas and No. 2 and No. 4 fuel oil. LDEQ's SIP submittal demonstrates that the two units at Ninemile Point are subject to BART. LDEQ and Entergy entered into an AOC limiting fuel oil to ULSD with a sulfur content of 0.0015%. As the BART Guidelines state "if a source commits to a BART determination that consists of the most stringent controls available, then there is no need to complete the remaining analyses."[66] Entergy states that during the baseline period these units burned fuel oil with an average sulfur content of 0.3%. Switching to ULSD will result in a reduction of SO_2 emissions by over 99%. We find that ULSD is the most stringent control available for addressing SO_2 emissions and we agree with LDEQ that this satisfies BART for SO_2 for Ninemile Point Units 4 and 5.

For PM BART for Units 4 and 5, Louisiana evaluated wet ESP, wet scrubber, cyclones, and switching fuels to ULSD. In evaluating energy and non-air quality impacts, the BART analysis identifies energy impacts associated with energy usage for ESPs and scrubbers. In addition, ESPs

---

[64] AP 42, Fifth Edition, Volume 1, Chapter 1: External Sources, Section 1.4, Natural Gas Combustion, available here: *https://www3.epa.gov/ttn/chief/ap42/ch01/final/c01s04.pdf.*

[65] See TSD for summary of PM control cost analysis.

[66] See 40 C.F.R. Part 51, Appendix Y, IV, D

and scrubbers generate wastewater streams and the resulting wastewater treatment will generate filter cake, requiring land-filling. LDEQ did not identify any impacts regarding the remaining useful life. The cost of compliance for these add-on control options is very high compared to the anticipated visibility benefits of controls. The modeled visibility benefits of add-on controls are very small and range from 0 dv to 0.08 dv for cyclone, wet scrubber and wet ESP. The BART analyses in the 2017 Louisiana Regional Haze SIP demonstrate that the cost of retrofitting the Units 4 and 5 with add-on PM controls would be extremely high compared to the visibility benefit for any of the units.[67] We believe that the cost of add-on PM controls does not justify the minimal expected improvement in visibility for these units. Accordingly, we are proposing to agree with LDEQ's determination that the fuel content limits for oil burning contained in the AOC that were determined to meet SO_2 BART also satisfy PM BART for Units 4 and 5.

3.6 Our BART Analysis for Waterford 1 & 2

Entergy operates three BART-eligible units at the Waterford 1 & 2[68] Generating Plant (Waterford) in St. Charles Parish, Louisiana. Unit 1 is an EGU boiler with a maximum heat input capacity of 4,440 MMBtu/hr that burns primarily natural gas and No. 6 fuel oil as its secondary fuel. Unit 2 is an EGU boiler with a maximum heat input capacity of 4,440 MMBtu/hr that burns primarily natural gas and No. 6 fuel oil as its secondary fuel. The auxiliary boiler (77 MMBtu/hr) burns only natural gas. We propose to approve the determination that Waterford Units 1 and 2, and the auxiliary boiler are subject-to-BART.

The 2017 Louisiana Regional Haze SIP narrative does not include a BART determination for the auxiliary boiler, but the BART analysis in Appendix D of the 2017 SIP submittal does address the auxiliary boiler and concludes that no additional controls are necessary for BART. The auxiliary boiler only burns natural gas. We note that SO_2 and PM emissions for gas-only units are inherently low,[69] so the installation of any additional PM or SO_2 controls on such units would likely achieve very low emissions reductions and minimal visibility benefits. As there are no appropriate add-on controls, and the status quo reflects the most stringent controls, we propose to agree with Louisiana that SO_2 and PM BART is no additional controls for the Waterford auxiliary boiler.

In assessing SO_2 BART for Units 1 and 2, Louisiana considered the five BART factors, which we discuss below.

3.6.1 Step 1: Identify All Available Retrofit Control Technologies for Waterford 1 & 2

---

67 See TSD for summary of PM control cost analysis.

68 Note that the name of this facility is "Waterford 1 & 2" and is also has units that are referred to as "Unit 1" and "Unit 2".

69 AP 42, Fifth Edition, Volume 1, Chapter 1: External Sources, Section 1.4, Natural Gas Combustion, available here: *https://www3.epa.gov/ttn/chief/ap42/ch01/final/c01s04.pdf.*

In Step 1, SO_2 control technologies of DSI, SDA, wet scrubbing, and fuel switching were identified as available controls. For gas-fired units that occasionally burn fuel oil, the BART Guidelines recommend: "For oil-fired units, regardless of size, you should evaluate limiting the sulfur content of the fuel oil burned to 1 percent or less by weight."[70] The Waterford units have only burned residual fuel oil (No. 6). Entergy states that these units are only physically capable of burning No. 6 fuel oil when not burning natural gas and evaluated switching to 0.5% sulfur No. 6 fuel oil, the lowest sulfur specification No. 6 fuel oil available.

The following is a summary of the type and amount of fuel oil burned by Units 1 and 2 from 2011 to 2015, inclusive. These units primarily burn natural gas, but also burn some fuel oil[71]:

Table 8: Fuel Oil Burning Types and Quantities

Plant Name	Boiler Id	Reported Fuel Type Code	Total Fuel Consumption Quantity	Year	Maximum Fuel Oil Sulfur Content (wt %)	Average Fuel Oil Sulfur Content (wt %)
Waterford 1 & 2	1	RFO	19,193	2011	0.50	0.50
Waterford 1 & 2	1	RFO	2,798	2012	0.84	0.84
Waterford 1 & 2	1	RFO	5,165	2013	0.08	0.08
Waterford 1 & 2	1	RFO	21	2014	0.99	0.99
Waterford 1 & 2	1	RFO	8,831	2015	0.96	0.96
Waterford 1 & 2	2	RFO	11,666	2011	1.04	0.95
Waterford 1 & 2	2	RFO	0	2012	NR	NR
Waterford 1 & 2	2	RFO	0	2013	NR	NR
Waterford 1 & 2	2	RFO	2,443	2014	0.50	0.50
Waterford 1 & 2	2	RFO	2,526	2015	0.96	0.96

Note that in the above table, "NR" means that no sulfur content data was reported for that year.

3.6.2 Steps 2 and 3: Identification of Technically Feasible SO_2 Retrofit Control Technologies and Control Effectiveness for Waterford 1 & 2

In Step 2, Louisiana eliminated all controls as technically infeasible with the exception of fuel switching. We disagree with this assessment as we are aware of instances, although not at any facility in the U.S., in which FGDs of various types have been installed or otherwise deemed

[70] 70 FR 39103, 39171 (July 6, 2005) [40 CFR 51, App. Y].

[71] Data acquired from EIA Form 923, available here: http://www.eia.gov/electricity/data/eia923/ This and other data are summarized in the file, "LA BART Fuel Oil Cost Analysis.xlsx," which is present in our docket. In this table, "DFO" means Distilled Fuel Oil, "RFO" means "Residual Fuel Oil," and one barrel is 42 gallons.

feasible on a boiler that burns oil.[72] Louisiana's submittal does not contain any site-specific information that distinguishes the Waterford units such that this technology would not be technically feasible. Consequently, we consider the installation of various types of scrubbers to be technically feasible and have supplemented Louisiana's analysis with our own. However, we propose to conclude from our analysis, that even if the LDEQ included analyses of these other control options, we believe the State's BART conclusion for Waterford would still be reasonable.[73] In addition to burning lower sulfur fuel oils, post-combustion controls also exist. Identification of technically feasible SO_2 retrofit control technologies can be established by searching our 2015 Air Markets Program Data,[74] supplemented with EIA 860 and 923 data,[75] for any EGUs that primarily fires gas and secondarily fire fuel oil, to determine what, if any, SO_2 controls have been installed for these types of units. The only units with these criteria that indicated any type of SO_2 control are the E W Brown Units 10 and 11, which are simple cycle combustion turbines with nameplate capacities of 126 MW. Our Air Markets Program Data listed the SO_2 control as "Other." Two other units from the E W Brown facility: Units 8 and 9, also listed having 126 MW combustion turbines with the SO_2 control listed as "Other." We assume this is something other than a scrubber or DSI, as this category lists all known variations of these types of technologies for other types of EGUs. An examination of EIA data did not indicate any type of SO_2 control was present for any of these units. Regardless, these EGUs are combustion turbines and all of the gas-fired units that are under consideration here are steam turbines.

Nevertheless, we are aware of instances in which FGDs of various types have been installed or otherwise deemed feasible on a boiler that burns oil either primarily or secondarily.[76] Consequently, the installation of various types of scrubbers is technically feasible. Because we are unaware of any scrubber installations on oil fired units in the U. S., we have no information on their control effectiveness. However, we see no technical reason why the control effectiveness of FGDs installed on gas-fired units that occasionally burn fuel oil should not be equal to that of FGDs installed on coal-fired units.

---

[72] Crespi, M. "Design of the FLOWPAC WFGD System for the Amager Power Plant." Power-Gen FGD Operating Experience, November 29, 2006, Orlando, FL; Babcock and Wilcox. "Wet Flue Gas Desulfurization (FGD) Systems Advanced Multi-Pollutant Control Technology." See Page 4: "We have also provided systems for heavy oil and Orimulsion fuels." DePriest, W; Gaikwad, R. "Economics of Lime and Limestone for Control of Sulfur Dioxide." See page 7: "A CFB unit, in Austria, is on a 275 MW size oil-fired boiler burning 1.0-2.0% sulfur oil."

[73] We believe that the installation of any of these other add-on control options, such as a scrubber, on any of these gas-fired units that occasionally burn oil results in very high cost-effectiveness values.

[74] https://ampd.epa.gov/ampd/

[75] http://www.eia.gov/electricity/data/eia860/index.html, http://www.eia.gov/electricity/data/eia923/

[76] Crespi, M. "Design of the FLOWPAC WFGD System For The Amager Power Plant." Power-Gen FGD Operating Experience, November 29, 2006, Orlando, FL.
Babcock and Wilcox. "Wet Flue Gas Desulfurization (FGD) Systems Advanced Multi-Pollutant Control Technology." See Page 4: "We have also provided systems for heavy oil and Orimulsion fuels."
DePriest, W; Gaikwad, R. "Economics of Lime and Limestone for Control of Sulfur Dioxide." See page 7: "A CFB unit, in Austria, is on a 275 MW size oil-fired boiler burning 1.0-2.0% sulfur oil."

The control effectiveness of switching from a higher sulfur fuel oil to a lower sulfur fuel oil lies in the reduction of sulfur. This depends on the percentage reduction from the sulfur contents of the fuel oil that forms the SO_2 baseline to the replacement fuel oil. Ultimately, the highest level of control would result from a switch to ultra-low sulfur diesel, which has a sulfur content of 0.0015%. This would equate to a control effectiveness of over 99%.[77] Lesser levels of controls are also possible. We include a discussion of a range of control effectiveness in switching to lower sulfur fuel oils in the next section.

3.6.3 Steps 3 and 4: Evaluation of Remaining Control Technologies and Impacts for Waterford 1 & 2

This section includes the control cost analyses for those subject to BART units at Waterford 1 & 2. Louisiana's SIP calculates the cost-effectiveness of these units switching to lower sulfur fuel oils. However, Louisiana did not provide any documentation for the figures used in these calculations. Because of this, we have supplemented Louisiana's BART analysis with our own. In addition, based on our discussion of technically feasible controls above, this TSD also includes the cost-effectiveness of installing scrubbers.

3.6.3.1 Step 3: Evaluation of Control Effectiveness of Lower Sulfur Fuel Oil for Waterford 1 & 2

As we discussed in our recent Texas BART FIP proposal, we did not see a regular correspondence between the reported amount and sulfur content of the fuel oil burned with the reported SO_2 emissions for the Texas units we analyzed. In other words, according to the data we presented, a barrel of fuel oil burned with about the same sulfur content did not result in the same amount of SO_2 emitted over time, nor did the expected trend always occur in the right direction.[78] We examine that same issue for these units in Louisiana. Below, we present both the reported and calculated annual SO_2 values for the units at Little Gypsy, Ninemile Point, Waterford, and Willow Glen that primarily burn gas but also burn some fuel oil:[79]

Table 9. Calculated versus Reported SO_2

Plant Name	Boiler Id	Reported Fuel Type Code	Year	Total Fuel Consumed (barrels)	EPA Calculated SO_2 (tons)	Monitored SO_2 (tons)
Waterford 1 & 2	1	RFO	2011	19,193	31.64	69.1
Waterford 1 & 2	1	RFO	2012	2,798	7.75	9.4
Waterford 1 & 2	1	RFO	2013	5,165	1.36	17.4

[77] Assuming baselines of 0.5% and 1%: (0.5 – 0.0015)/0.5 = 99.7%; (1.0 – 0/0015)/1.0 = 99.85%.
[78] Technical Support Document for the Texas Regional Haze BART Federal Implementation Plan (BART FIP TSD), November 2016, (Revised December 2016). See discussion in section 5.3.5.1.
[79] See the file, "LA BART Fuel Oil Cost Analysis.xlsx" in our docket for more details.

Waterford 1 & 2	1	RFO	2014	21	0.07	1.8
Waterford 1 & 2	1	RFO	2015	8,831	27.95	33.2
Waterford 1 & 2	2	RFO	2011	11,666	39.97	45.1
Waterford 1 & 2	2	RFO	2012	0	0.00	2.3
Waterford 1 & 2	2	RFO	2013	0	0.00	1.8
Waterford 1 & 2	2	RFO	2014	2,443	4.03	3.7
Waterford 1 & 2	2	RFO	2015	2,526	8.00	11.4

In the above table, the "EPA Calculated SO_2" values were calculated by applying SO_2 emission factors from AP 42.[80] We see the same issues echoed here, albeit to a lesser degree. For instance, the Waterford Unit 1 calculated SO_2 emissions for 2011 is 31.64 tons, while the monitored value is 45.1 tons. However, while the calculated value for this unit in 2015 is slightly less at 27.95 tons, the monitored value is less than half at 33.2 tons. Some of that may be explained because the unit operated much less in 2015 and would have monitored slightly less sulfur from the very small amount present in its primary fuel – pipeline natural gas. However, we believe it is more likely a result of inaccuracies in either the quantity and/or sulfur content of the fuel oil reported to EIA. As a consequence of this discordance between the reported type and amount of fuel oil burned and the reported SO_2, we cannot rely on historical SO_2 emissions to construct a baseline, because a barrel of fuel oil with a given reported sulfur content does not result in a consistent reported SO_2 value over time.

However, information from the EIA indicates that fuel oil of varying sulfur contents is widely available across the U.S. EIA reports the prices for various refinery petroleum products on a monthly and annual basis. Below is summary of various distillate and residual fuel oil products for 2001 to 2015, averaged across the U.S."[81]

Table 10. Selected EIA Reported Annual Refiner Petroleum Prices

Date	West Texas Intermediate Crude Oil – Cushing Oklahoma ($/bbl)	U.S. No 2 Diesel Wholesale/ Resale Price by Refiners ($/Gallon)	U.S. No. 2 Fuel Oil Wholesale/ Resale Price by Refiners ($/Gallon)	U.S. No 4 Distillate Wholesale/ Resale Price by Refiners ($/Gallon)	U.S. Residual Fuel Oil Sulfur Less Than or Equal to 1% Wholesale/Resale Price by Refiners ($/Gallon)
2015	48.66	1.667	1.565	1.215	0.971
2014	93.17	2.812	2.741	2.333	2.153
2013	97.98	3.028	2.966	2.767	2.363
2012	94.05	3.109	3.031		2.548

[80] The emission factors were taken from AP 42, Fifth Edition, Volume 1, Chapter 1: External Sources, Section 1.3, Fuel Oil Combustion, available here: https://www3.epa.gov/ttn/chief/ap42/ch01/index.html. Boilers > 100 Million Btu/hr. In these emission factors, S = weight % sulfur and is multiplied by 150 for No. 4, 157 for RFO and 142 for No. 2 and ULSD.
[81] EIA Refiner Petroleum Product Prices by Sales Type, available here: http://www.eia.gov/dnav/pet/pet_pri_refoth_dcu_nus_a.htm http://www.eia.gov/dnav/pet/pet_pri_spt_s1_a.htm

2011	94.88	3.034	2.907	2.801	2.389
2010	79.48	2.214	2.147		1.756
2009	61.95	1.713	1.657	1.561	1.337
2008	99.67	2.994	2.745	2.157	1.918
2007	72.34	2.203	2.072	1.551	1.406
2006	66.05	2.012	1.834	1.395	1.202
2005	56.64	1.737	1.623	1.377	1.115
2004	41.51	1.187	1.125	1.033	0.764
2003	31.08	0.883	0.881	0.793	0.728
2002	26.18	0.724	0.694	0.663	0.546
2001	25.98	0.784	0.756	0.697	0.523
2000	30.38	0.898	0.886	0.778	0.627

As can be seen from the above table, the price of these fuel oils closely tracks the price of crude oil, and are fairly volatile.

3.6.3.2 Step 4: : Evaluation of Impacts of Lower Sulfur Fuel Oil for Waterford 1 & 2

Lacking facility-specific pricing information, for the purposes of calculating the cost of compliance,[82] we make the following assumptions in our evaluation of Part 1 to Step 4:

- Fuel oil costs can be based on the 2015 U.S. average prices as reported in Table 10:
- Residual fuel oil is the type of fuel oil currently available that most closely approximates the types of fuel oil that were historically burned by the Waterford Units 1 and 2. Residual fuel oil pricing is available with sulfur contents less than or equal to 1% and greater than 1%. Based on the EIA data in Table 8, we will use the cost of residual fuel oil with a sulfur content of less than or equal to 1% in constructing "business as usual" scenarios of the annual cost of fuel oil for the Waterford units.
- Based on the historical fuel oil sulfur contents, a sulfur content of 1% by weight is appropriate to use as a baseline for Waterford Units 1 and 2.
- No. 2 fuel oil is available at approximately 3,000 ppm (0.3% sulfur content by weight), which roughly corresponds to the sulfur level present in No. 2 fuel oil prior to our implementation of the Ultra-Low-Sulfur Diesel (ULSD) regulations.[83] We will use the cost of this fuel oil in constructing a "medium control" annual cost of fuel oil.
- No. 2 diesel fuel corresponds to ULSD, with a sulfur content of 15 ppm (0.0015% sulfur content by weight). We will use the cost of this fuel oil in constructing a "high control" annual cost of fuel oil.

---

[82] We note that Entergy has provided cost-effectiveness figures for switching the Little Gypsy Unit 2, the Waterford Unit 1 and 2, and Ninemile Units 4 and 5. However, no documentation of the costs of the current and lower sulfur fuel oils, the total annualized costs, or how Entergy projected how much fuel oil would be burned in the future were provided to support these figures. Due to this lack of documentation we were unable to use these figures.

[83] 69 FR 38957, 39073 (June 29, 2004): "Both high sulfur No. 2–D and No. 2 fuel oil must contain no more than 5000 ppm sulfur,131 and currently [as of the date of our final rule, 6/29/04] averages 3,000 ppm nationwide."

- The Waterford units have historically only burned residual fuel oil and we assume that the capital costs necessary to enable these units to burn distillate fuel oil are minor. We invite the facility owner, Entergy, to provide a cost estimate for the modification to burn distillate fuel oils should it disagree with this assumption.
- The emission factor for calculating the tons of sulfur emitted by the fuel oils can be taken from AP 42.[84]

The cost of switching fuel oil types is below:[85]

Table 11. Control Cost Analysis for Fuel Oil Switching from Residual Fuel Oil Baseline

Baseline: Residual Fuel Oil <=1%			
	Cost for 1,000 barrels ($/yr)	Tons reduced per 1,000 barrels	Cost effectiveness ($/ton)
Business as usual (Residual Fuel Oil @ 1% S and $0.971/gal)	$40,782		
Moderate control (No. 2 fuel oil @ 0.3% S and $1.565/gal)	$65,730	2.40	$10,385
High control (ULSD @ 0.0015% S and $1.667/gal)	$70,014	3.29	$8,878

Although the cost-effectiveness of switching to a lower sulfur oil is less attractive (higher $/ton) than other controls typically required under BART, we note certain mitigating factors. For instance, unlike the cost estimates for wet FGD and SDA scrubbers for coal fired units, which have large capital costs, we are unaware of any significant capital costs involved in switching fuels. Also, because the units in question have only occasionally burned fuel oil, they have the option to avoid the cost of fuel switching entirely by entering a permanent and enforceable mechanismthat limits the units to burning their primary fuel of natural gas. Lastly, the prevalence of ULSD in the fuel oil market is such that it appears to be gradually replacing most other No. 2 fuel oil applications.[86]

In evaluating Parts 2, 3, and 4 to Step 4, we do not see any energy impacts associated with switching to fuel oils with a lower sulfur content. Similarly, we do not see any non-air quality environmental impacts associated with switching to fuel oils with a lower sulfur content. Furthermore, we are unaware that any of the units under consideration have entered into an enforceable document to shut down that unit earlier, nor do we see any reason to conclude that simply switching to a lower sulfur oil will affect the lifetime of any of these units.

---

[84] For example, the SO2 emission factor for No. 4 oil is 150 X S, where S = weight % sulfur, taken from AP 42, Fifth Edition, Volume 1, Chapter 1: External Sources, Section 1.3, Fuel Oil Combustion, available here: https://www3.epa.gov/ttn/chief/ap42/ch01/index.html. Boilers > 100 Million Btu/hr.

[85] See the file, "LA BART Fuel Oil Cost Analysis.xlsx" for the calculations and supporting data for these figures.

[86] http://www.eia.gov/todayinenergy/detail.php?id=5890. http://blogs.platts.com/2014/05/07/heating-oil-new-york-sulfur/. http://oilandenergyonline.com/challenges-to-the-northeast-supply-picture/

3.6.3.3 Steps 3 and 4: Evaluation of Control Effectiveness and Impacts of Scrubbers for Waterford 1&2

Earlier, we concluded that certain types of wet scrubbers were technically feasible as potential control options for gas boilers that occasionally burn oil, similar to the ones under BART review here. Were we to calculate the cost effectiveness of a wet FGD, we could expect that the capital and operating costs would minimally be on the order of $15,000,000/year, based on cost analyses on similarly sized EGUs were have performed in the past. The installation of such a scrubber on any of the gas-fired units that occasionally burn oil results in a very high cost-effectiveness because of the relatively low amount of fuel oil actually burned since 2011. For instance, assuming only 1/5 the potential total annualized cost, or $3,000,000, and dividing it by five times the maximum SO_2 tonnage of any of the units in Table 9, or 345.5 tons, results in a cost-effectiveness of greater than $8,600/ton.

Next, we evaluate Parts 2, 3, and 4 to Step 4, in our evaluation of the control effectiveness and impacts of scrubbers, the energy and non-air quality environmental impacts, and remaining useful life considerations associated with installing scrubbers. The use of scrubbers does result in some energy impacts and non-air quality considerations. Energy from the facility is used to power both SDA and wet FGD systems. Also, in both scrubbing systems, a waste product is generated. Both wet FGD and SDA require water but a typical wet FGD requires more water than does an SDA . However, because both SDA and wet scrubbing systems are in wide use throughout the U. S., we do not consider these issues consequential, with cost being the overrifing consideration in this instance. Entergy has not indicated that the Waterford 1 & 2 facility has any limits on its useful life, so we do not consider that issue.

3.6.4 Step 5: Evaluation of Visibility Impacts for Waterford 1 & 2

In assessing the visibility benefits of fuel switching, Louisiana submitted CALPUFF modeling for 1% sulfur and 0.5% sulfur fuel oil. We performed additional CALPUFF modeling to correct for errors in the modeling and to evaluate the visibility benefits of additional fuel types. See the CALPUFF Modeling TSD for additional information on modeling inputs and results. The visibility benefits from fuel switching are summarized in Table 12.

Table 12. Visibility Benefits of Fuel Switching at Waterford (CALPUFF, 98th percentile)

	Class I area	Baseline Impact (dv)	Visibility benefit (dv) of 0.5% S	Visibility benefit (dv) of 0.3% S	Visibility benefit (dv) of 0.0015% S
Unit 1	Breton	2.704	0.883	1.348	1.744
Unit 2	Breton	2.378	0.798	1.207	1.601

3.6.5 Evaluation of PM BART for Waterford 1 & 2

For PM BART for Units 1 and 2, Louisiana evaluated wet ESP, wet scrubber, cyclones, and switching fuels to 0.5% S fuel oil. In evaluating energy and non-air quality impacts, Louisiana identified energy impacts associated with energy usage for ESPs and scrubbers. In addition, ESPs and scrubbers generate wastewater streams and the resulting wastewater treatment will generate filter cake, requiring land-filling. Louisiana did not identify any impacts regarding remaining useful life. The costs of compliance for these control options are very high compared to their anticipated visibility benefits. Modeled baseline visibility impacts from PM emissions are very low. Modeled visibility impairment from baseline PM emissions are less than 5% of the total modeled impact from the source.[87] Entergy's modeled visibility benefits of add-on controls are very small and range from 0 dv to 0.06 dv for cyclone, wet scrubber, and wet ESP for each unit.[88] The BART analyses in the 2017 Louisiana Regional Haze SIP demonstrate that the cost of retrofitting Units 1 and 2 with add-on PM controls would be extremely high compared to the visibility benefits for any of the units. LDEQ concluded that the costs of add-on PM controls do not justify the minimal expected improvement in visibility for these units. LDEQ included an analysis of fuel switching for PM BART in its SO_2 BART analysis, as PM reductions from fuel switching were also included in the assessment of benefits from fuel switching. Accordingly, we are proposing to agree with the determination in the 2017 Louisiana Regional Haze SIP that the fuel content limits for oil burning contained in the AOC that were determined to meet SO_2 BART also satisfy PM BART.

Table 13. Summary of Cost-Effectiveness ($/ton) for Waterford Unit 1 and 2 PM Add-on Controls[89]

	Cyclone	Wet Scrubber	Wet ESP
Unit 1	$34,817	$142,352	$477,382
Unit 2	$18,498	$80,637	$253,650

3.6.6 Our Proposed BART Determination for Waterford 1 & 2

The cost-effectiveness of switching to a lower sulfur fuel oil is less attractive (higher $/ton) than other controls we have typically required under BART. While the visibility benefits of switching fuel types are significant, the cost-effectiveness in terms of $/ton is in excess of $8,000/ton for the most stringent control option. We also note that the facility primarily operates by burning natural gas and the visibility benefits presented in Table 12 represent benefits only for those periods when fuel oil is burned and would not occur during natural gas operation. As discussed above, over the 2011-2015 period, the highest annual emissions for SO_2 reported for a unit at the facility is only 69 tons/year. Considering this, we propose to agree with the LDEQ's determination that no additional controls or fuel switching are necessary to satisfy BART. The LDEQ and Entergy have entered into an AOC limiting fuel oil sulfur content to 1% or less. This enforceable limit is consistent with past practice, the baseline level utilized in the BART analysis, and the minimum recommendation in the BART Guidelines. We encourage Louisiana

---

[87] See Table 3-3 and Table 3-4 of Entergy Louisiana, LLC, Little Gypsy Generating Plant, BART Five-Factor Analysis, Prepared by Trinity Consultants, November 9, 2015 revised April 14, 2016. Available in appendix D of the 2017 Louisiana Regional Haze SIP.

[88] See Table 5-8 and Table 5-9 of Entergy Louisiana, LLC, Little Gypsy Generating Plant, BART Five-Factor Analysis, Prepared by Trinity Consultants, November 9, 2015 revised April 14, 2016. Available in appendix D of the 2017 Louisiana Regional Haze SIP.

[89] Entergy Louisiana, LLC, Little Gypsy Generating Plant, BART Five-Factor Analysis, Prepared by Trinity Consultants, November 9, 2015 revised April 14, 2016. Available in appendix D of the 2017 Louisiana Regional Haze SIP.

and Entergy to reconsider switching to a lower sulfur fuel when assessing controls under reasonable progress for future planning periods.